# ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
# 40 CFR 146.84(b)

## Facility Information

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@crc.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

## Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Well completion, production, and injection data from the reservoir's entire depletion history

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CalCapture A1-A2 project, the AoR encompasses the maximum aerial extent of the $CO_2$ plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

***Model Background***

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the $CO_2$ plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of $CO_2$ in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of $CO_2$ and residual oil in the reservoir. Solubility of $CO_2$ in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of $CO_2$ stored and simulates lateral and vertical movement of the $CO_2$ to define the AoR.

The simulator predicts the evolution of the $CO_2$ plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the $CO_2$ plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of $CO_2$ after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous $CO_2$ sequestration peer reviewed papers, including:

1. Simulation of $CO_2$ EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of $CO_2$ Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

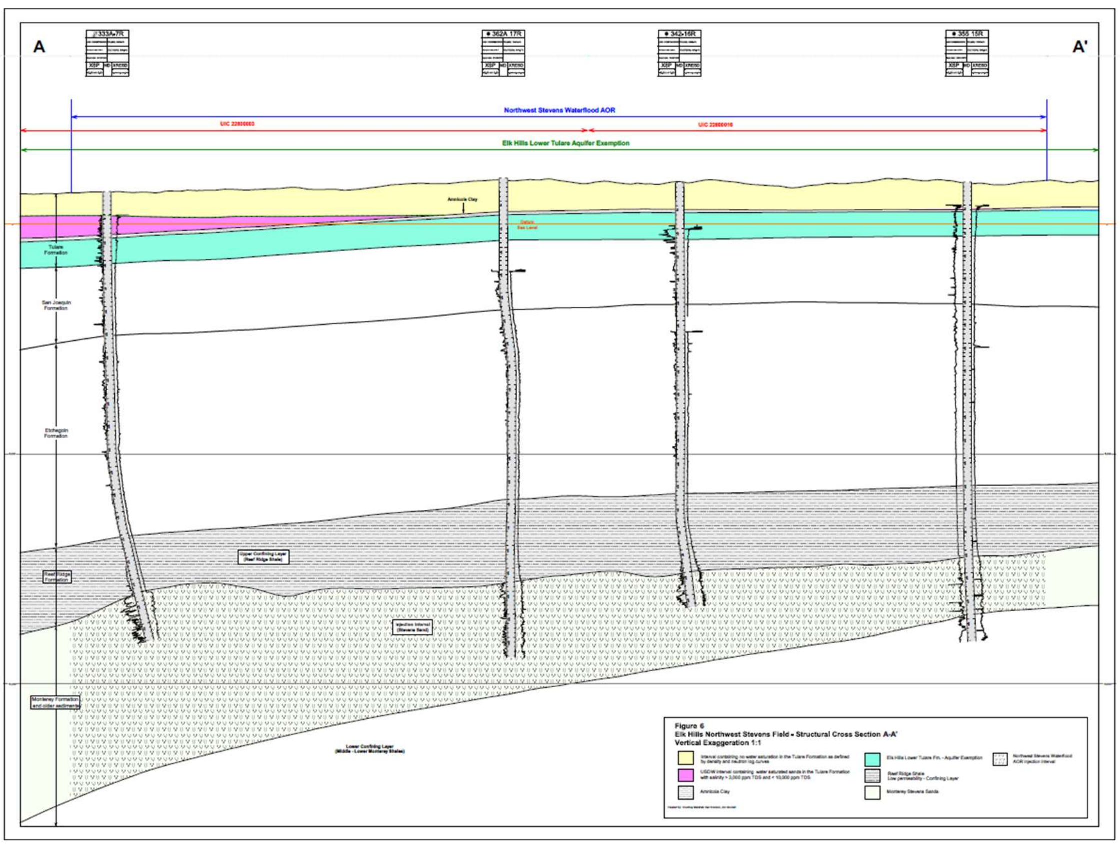
3. Geomechanical Risk Mitigation for $CO_2$ Sequestration in Saline Aquifers. Tran, Davis et al.

### *Site Geology and Hydrology*

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

**Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands pinching-out on the NWS anticline.**



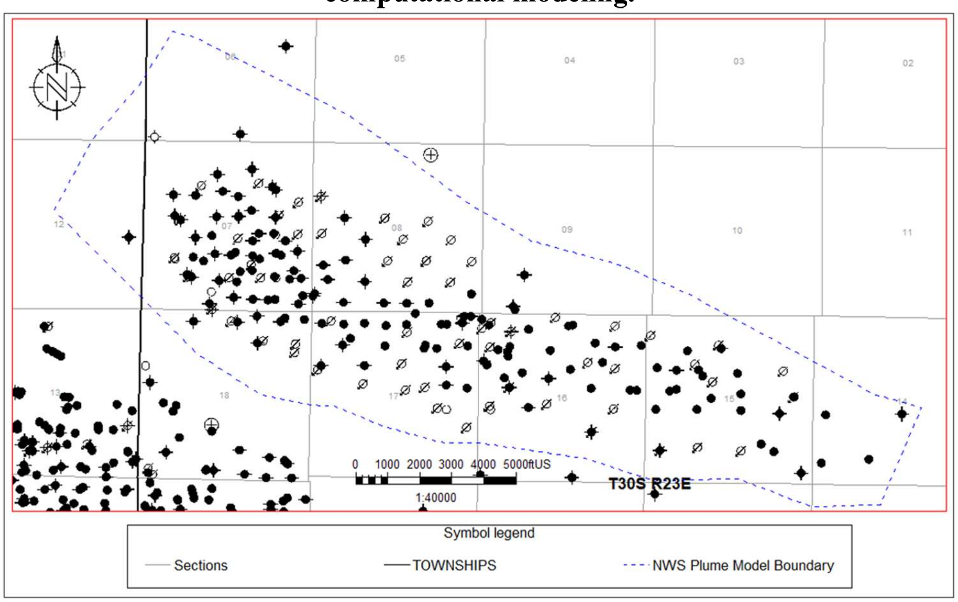

The CalCapture Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was “blown-down”, depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

**Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.**

| Process | Phase | Volume |
|---|---|---|
| Production | Oil | 28 million barrels |
| | Gas | 193 billion cubic feet |
| | Water | 9 million barrels |
| Injection | Water | 6 million barrels |
| | Gas | 175 billion cubic feet |

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

**Figure 2: Location of wells with open-hole log data used to develop the static model used in computational modeling.**




.

Model Domain

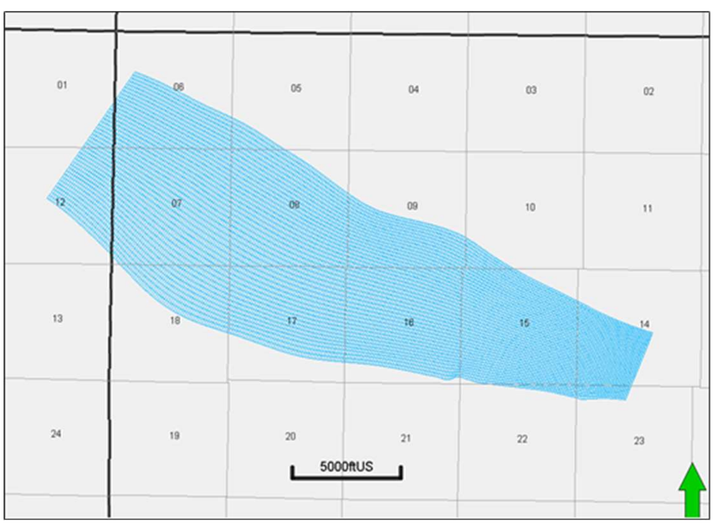
A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

**Table 2. Model domain information.**

| | | | |
|---|---|---|---|
| **Coordinate System** | State Plane | | |
| **Horizontal Datum** | NAD 83 | | |
| **Coordinate System Units** | Feet | | |
| **Zone** | CA83-VF | | |
| **FIPSZONE** | 0405 | **ADSZONE** | 3376 |
| **Coordinate of X min** | 6,095,241.81 | **Coordinate of X max** | 6,122,433.26 |
| **Coordinate of Y min** | 2,302,015.15 | **Coordinate of Y max** | 2,316,903.12 |
| **Elevation of bottom of domain** | -10,426.35 | **Elevation of bottom of domain** | -6,670.36 |

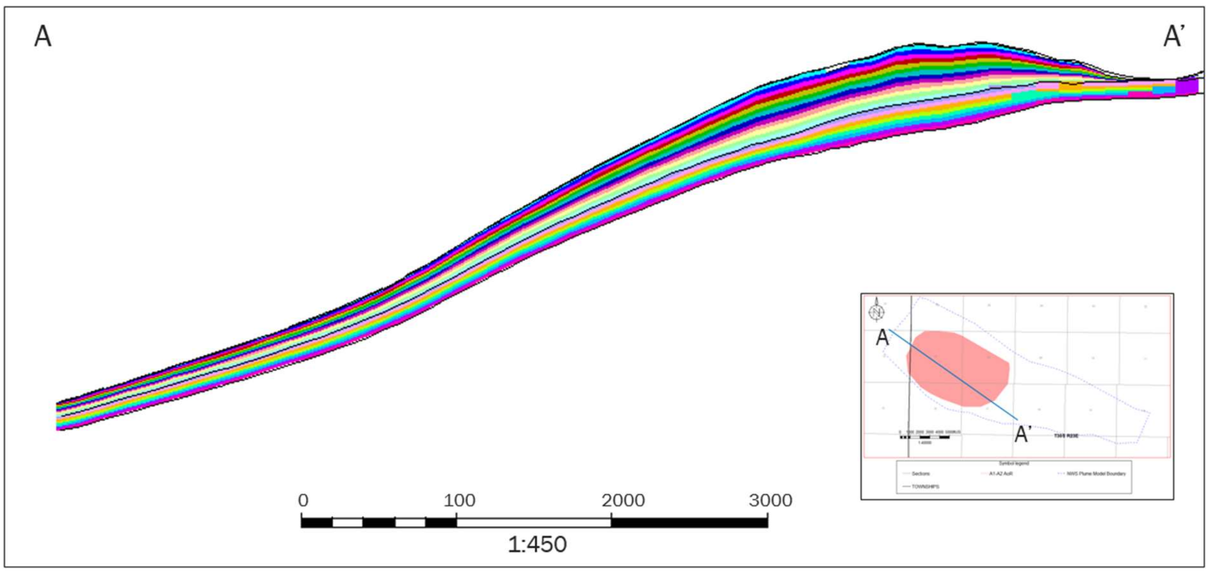
The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 3) at 150 feet x 150 feet. The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and the peripheral area of elevated pressure.

**Figure 3: Plan view of the model boundary showing the extent of the CO2 plume that defines the AoR.**



The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 layers (Figure 4) respectively and an average grid cell height of 11.5 feet. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing $CO_2$ movement. Well data that defines the stratigraphy also defines the structure of the A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

**Figure 4: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.**




### *Porosity and Permeability*

Figure 3 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 5) that is dependent on porosity and clay volume.

**Figure 5: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.**

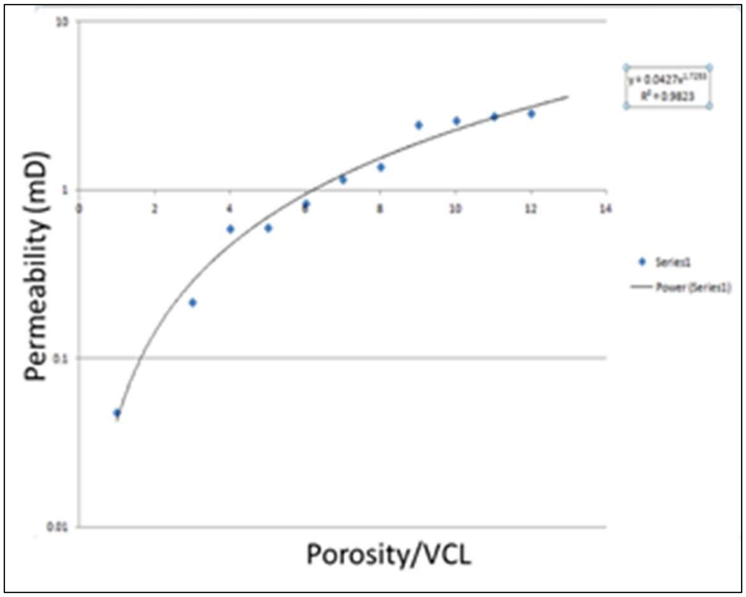



**Figure 6: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**

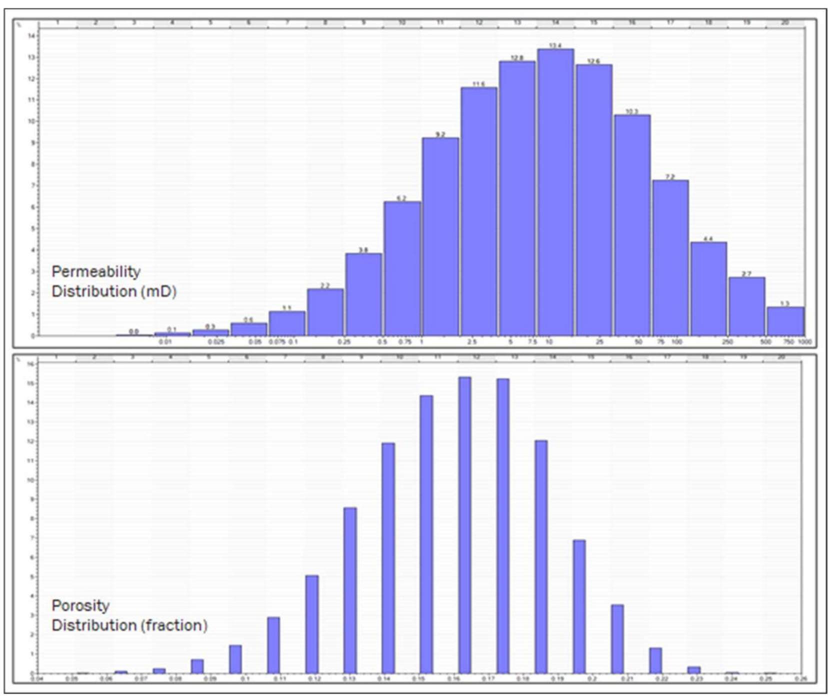
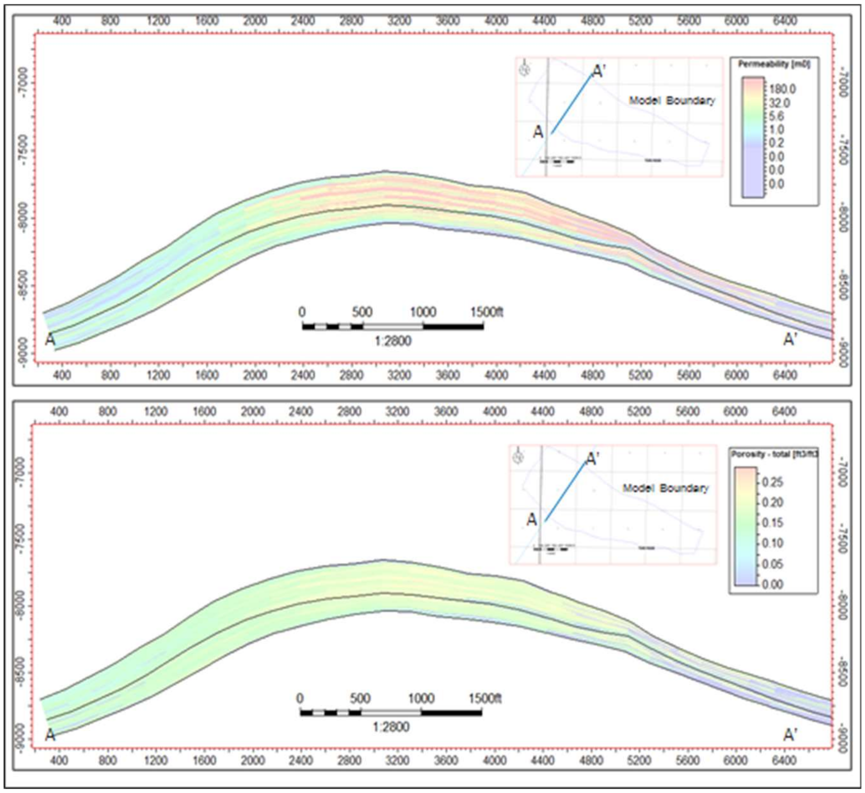



Figure 6 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 7 shows the permeability and porosity distribution in cross-section A-A'.

Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

**Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.**



### *Constitutive Relationships and Other Rock Properties*

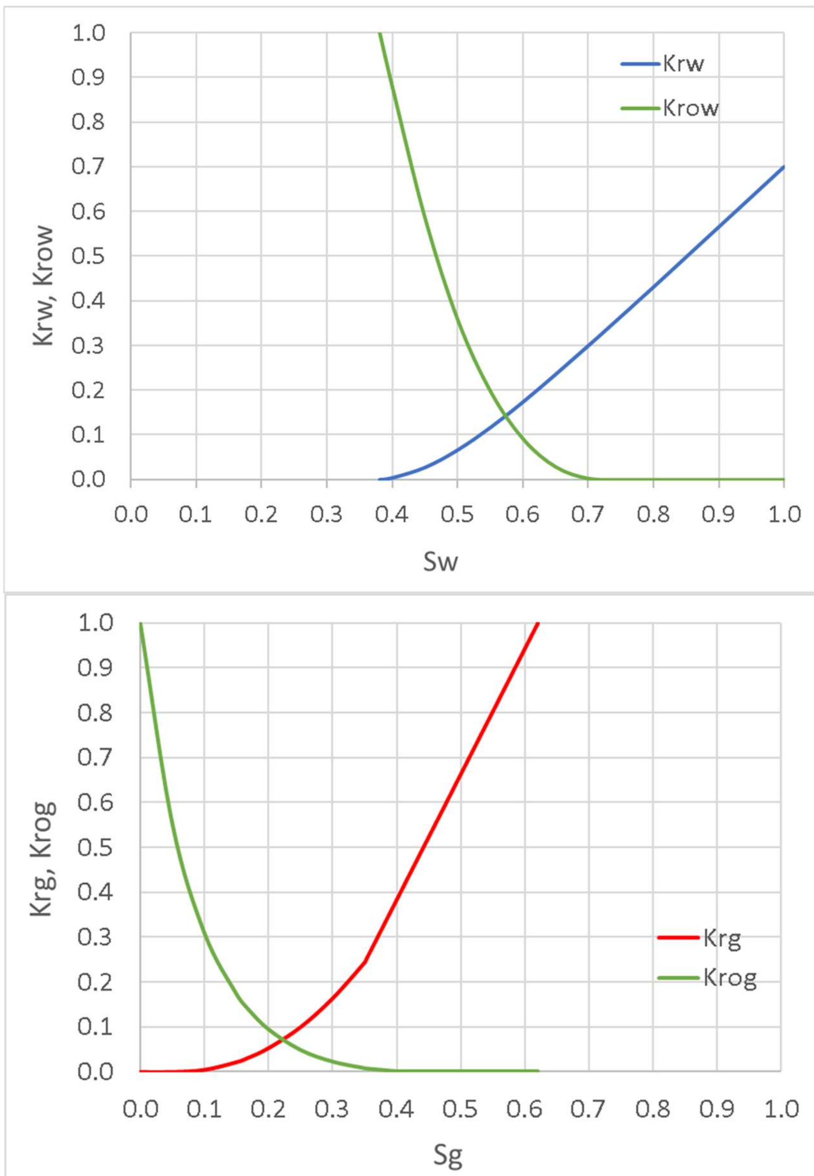
The Monterey Formation A1-A2 reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

**Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.**

| | Gas Cap | Oil Band | Water Zone |
|---|---|---|---|
| Contact (depth sub-sea) | Gas - Oil<br>8,400 | Oil - Water<br>8,550 | |
| Saturation (fraction) | Water: 0.18<br>Gas: 0.82 | Oil: 0.15<br>Water: 0.85 | Water: 1.0 |

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 8 shows the relative permeability curves used in the computational modeling.

**Figure 8: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.**



### *Boundary Conditions*

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

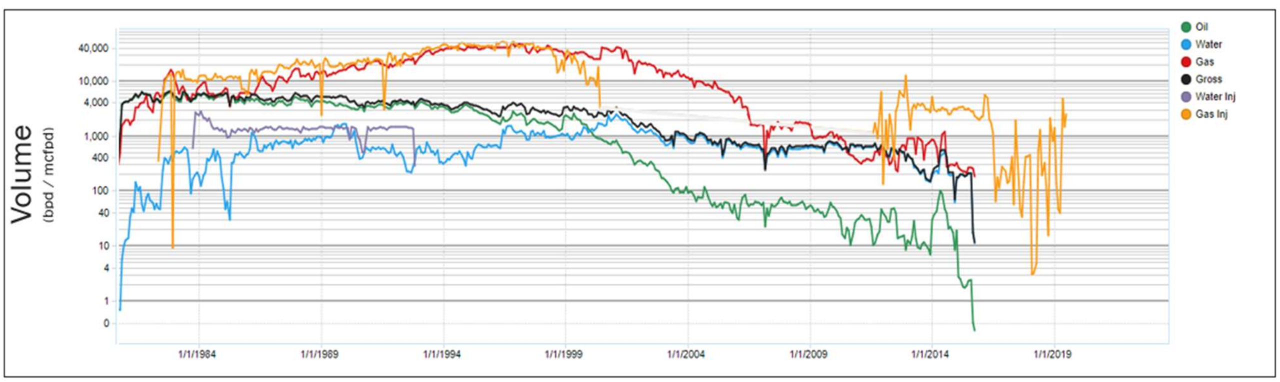
2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 9) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 9) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 230 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

**Figure 9: Monterey Formation A1-A2 production and injection data.**




### *Initial Conditions*

Initial model conditions (start of $CO_2$ injection) of the Monterey Formation A1-A2 reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

**Table 4. Initial conditions.**

| Parameter | Value or Range | Units | Corresponding Elevation (ft MSL) | Data Source |
|---|---|---|---|---|
| Temperature | 240 | Fahrenheit | 8,300 | Fluid Analysis |
| Formation pressure | 200-300 | Pounds per square inch | 8,300 | Pressure Test |
| Fluid density | 61 | Pounds per cubic foot | 8,300 | Water analysis |
| Salinity | 25,000 | Parts per million | 8,300 | Water analysis |

### *Operational Information*

Details on the injection operation are presented in Table 5.

**Table 5. Operating details.**

| Operating Information | Injection Well 1<br>357-7R | Injection Well 2<br>355-7R |
|---|---|---|
| Location (global coordinates)<br>X<br>Y | <br>35.32802963<br>-119.5449982 | <br>35.33139038<br>-119.5441437 |
| Model coordinates (ft)<br>X<br>Y | <br>6,100,956.63<br>2,308,944.30 | <br>6,101,103<br>2,310,474 |
| No. of perforated intervals | 7 | 4 |
| Perforated interval (ft MSL)<br>Z top<br>Z bottom | <br>7,728<br>8,010 | <br>7,774<br>7,949 |
| Wellbore diameter (in.) | 7 | 7 |
| Planned injection period<br>Start<br>End | <br>02/01/2024<br>04/01/2039 | <br>02/01/2024<br>04/01/2039 |
| Injection duration (years) | 15 | 15 |
| Injection rate (t/day)* | 648 – 1,917 | 648 – 1,917 |

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

### *Fracture Pressure and Fracture Gradient*

Calculated fracture gradient and maximum injection pressure values are given in Table 6.

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

CRC has also conducted tests to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field.

**Table 6: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.**

| Interval | Fracture Gradient PSI/foot | Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet) |
|---|---|---|
| Monterey Formation A1-A2 | 0.97 | 8,150 |

CTV will ensure that the injection pressure is beneath 90% of the fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (Table 7) using the Monterey Formation A1-A2 fracture gradient. The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI.

**Table 7. Injection pressure details.**

| **Injection Pressure Details** | **Injection Well 1 357-7R** | **Injection Well 2 355-7R** |
|---|---|---|
| Fracture gradient (psi/ft) | 0.97 | 0.97 |
| Maximum injection pressure (90% of fracture pressure) (psi) | 7,335 | 7,335 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 8,403 | 8,403 |
| Elevation at the top of the perforated interval (ft MSL) | 8,485 | 8,462 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 7,407 | 7,387 |
| Planned maximum injection pressure / gradient (top of perforations) | 4,500 / 0.53 | 4,500 / 0.53 |

## Computational Modeling Results

### *Predictions of System Behavior*

The following maps (Figure 10) and cross-sections (Figure 11) show the computational modeling results and development of the $CO_2$ plume at four –time-steps. For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the $CO_2$ injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the $CO_2$ injectate remains as super-critical $CO_2$.

**Figure 10: Plan view showing the plume development through time for layer 15. Note that the plume does not change from 50 years post injection to 100 years post injection.**

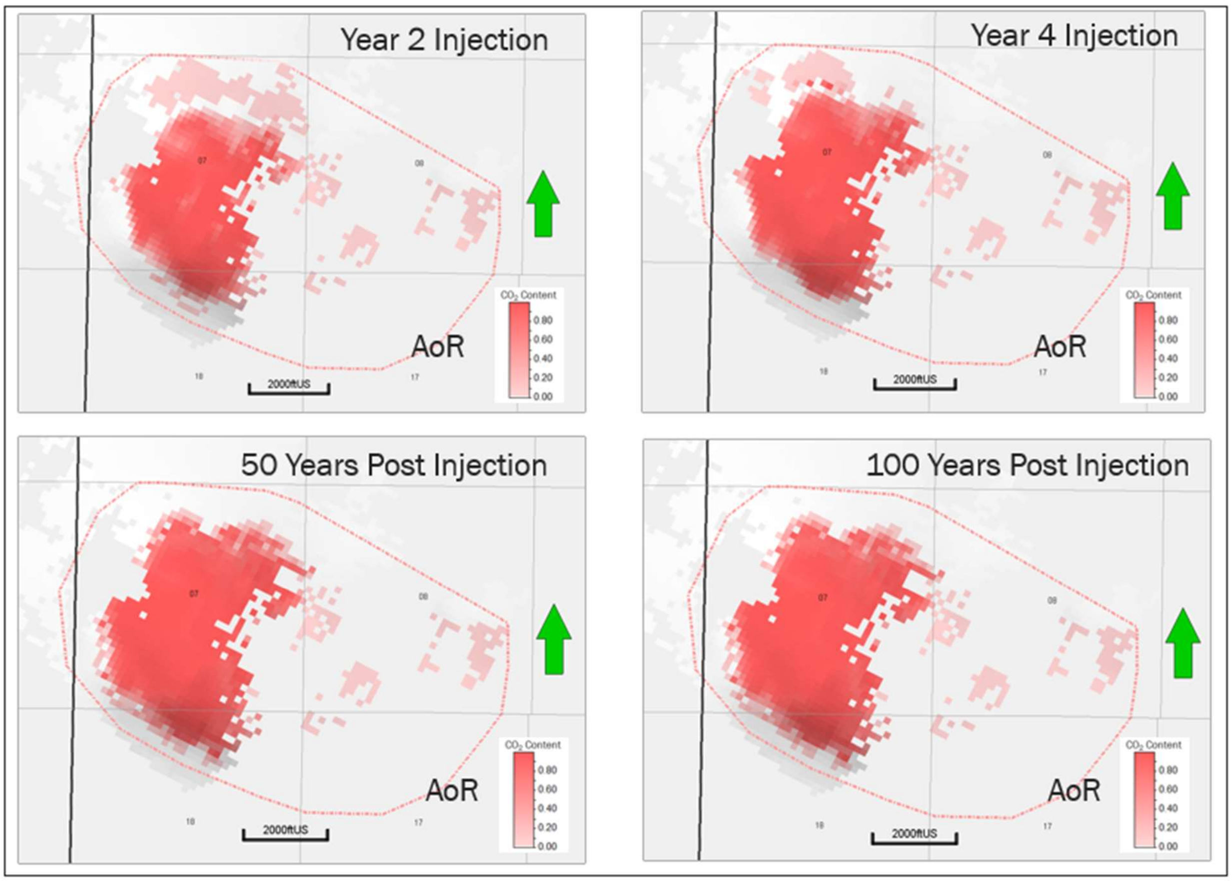
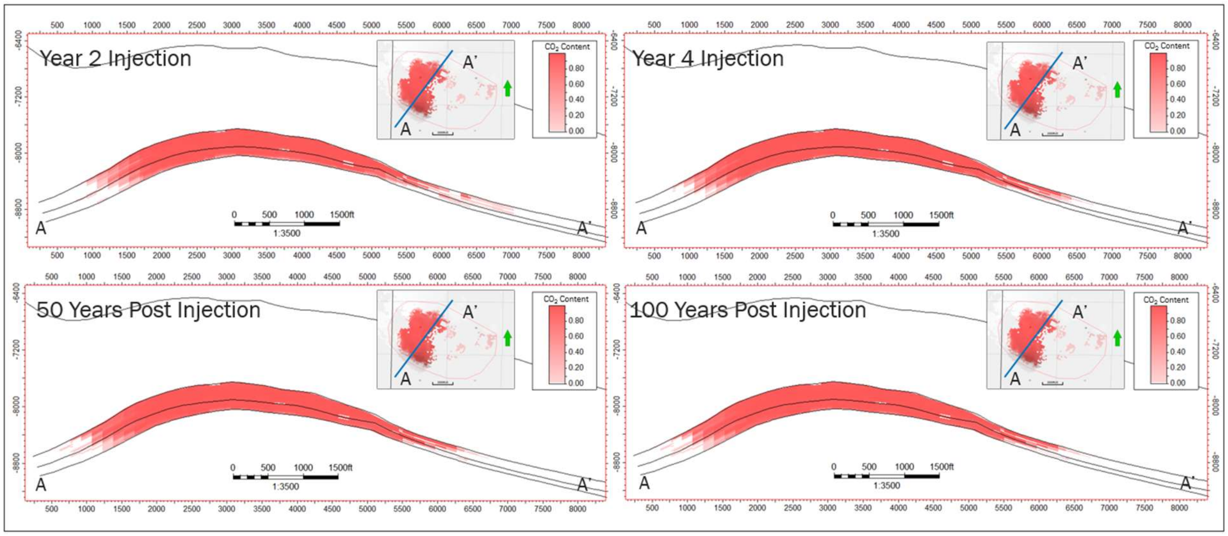
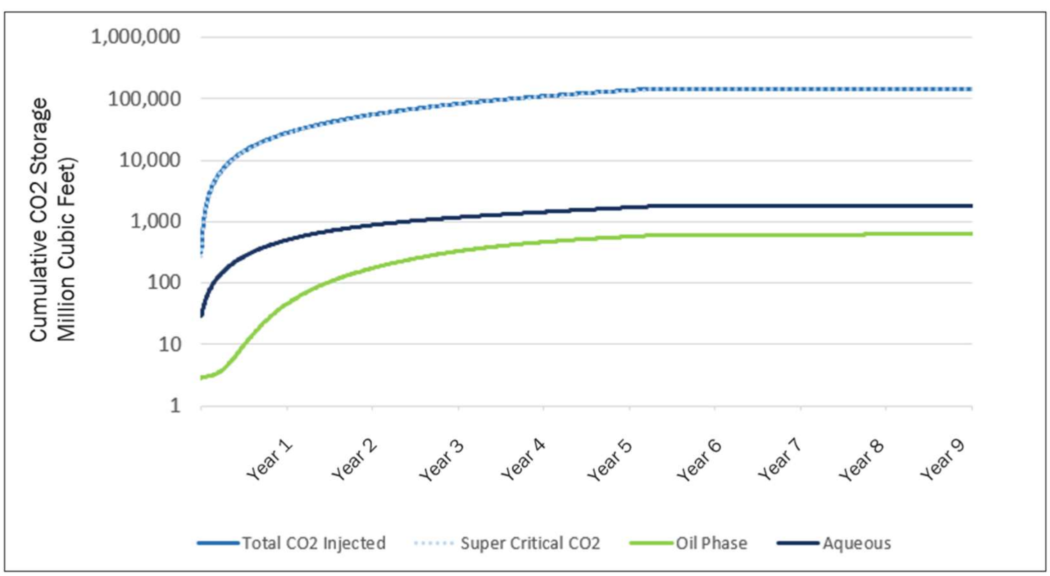


**Figure 11: Cross-sections showing the plume development through varying times through the project. Note that the plume does not change from 50 years post injection to 100 years post injection.**




$CO_2$ injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining saturation for oil and water in the depleted reservoir, total dissolved $CO_2$ in oil and water is only 0.5% and 1.3% of the $CO_2$ injected respectively. 98% of $CO_2$ injected is stored as super-critical $CO_2$. Figure 12 shows the cumulative storage for each of the mechanisms. After 5 years of injection, there is no additional change in the quantity of $CO_2$ dissolving in the oil and water.

**Figure 12: CO2 storage mechanisms in the reservoir.**

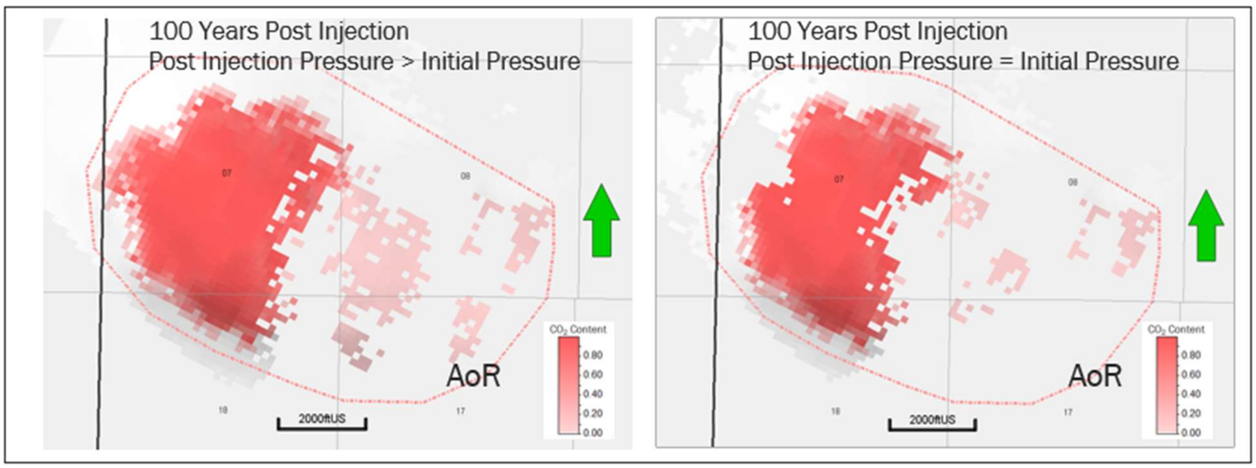


### *Model Calibration and Validation*

CRC has injected 175 BCF of gas into the Monterey Formation A1-A2 reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

As a computational model sensitivity, CTV maintained the injection rate for nine years, with an increase of the post-injection pressure and total $CO_2$ injected. At a final pressure of 5,750 psi, versus 4,000 psi, the reservoir can store 193 BCF of $CO_2$, an addition of 61 BCF $CO_2$. Figure 13 shows the difference in plume development at 100 years post injection. Note that the plume stays within the AoR, with increased $CO_2$ concentrations in cells in northwestern portion of the AoR.

**Figure 13: Plan view of plume development at layer 15 in the computational model.**




This scenario demonstrates that the AoR, as defined by the maximum extent of $CO_2$ injectate, is consistent with a larger volume of $CO_2$ injected. This provides confidence that the corrective action well review and potential impact to the Upper Tulare USDW is conservative.

## AoR Delineation

The AoR was determined by the largest extent of the $CO_2$ plume from computational modeling results. In the AoR scenario, $CO_2$ was injected into the depleted Monterey Formation A1-A2 reservoir until the reservoir pressure reached the discovery pressure of 4,000 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

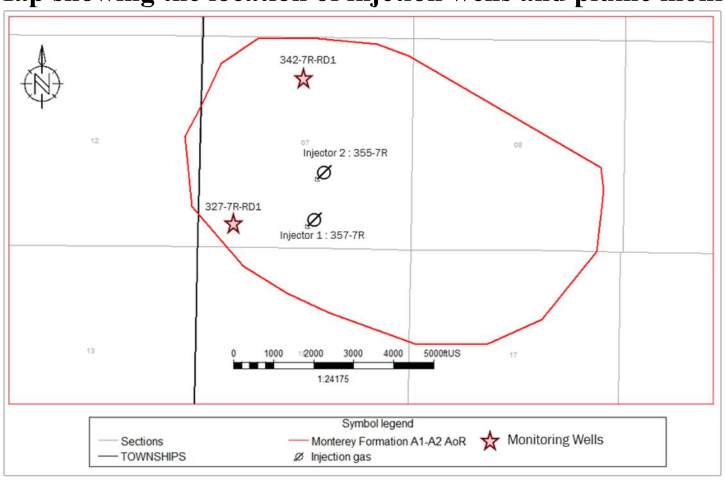
Figure 14 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and $CO_2$ plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. $CO_2$ plume and water contact will be calculated from monitoring well pressure, $CO_2$ saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

**Figure 14: Map showing the location of injetion wells and plume monitoring wells.**




## Corrective Action

### *Tabulation of Wells within the AoR*

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation A1-A2 reservoir was discovered in 1973 and developed subsequently. As such, there are excellent records for wells drilled in the field. There have been no “un-documented” historical wells found during the over 40-year development history of the reservoir that includes injection of water and gas.

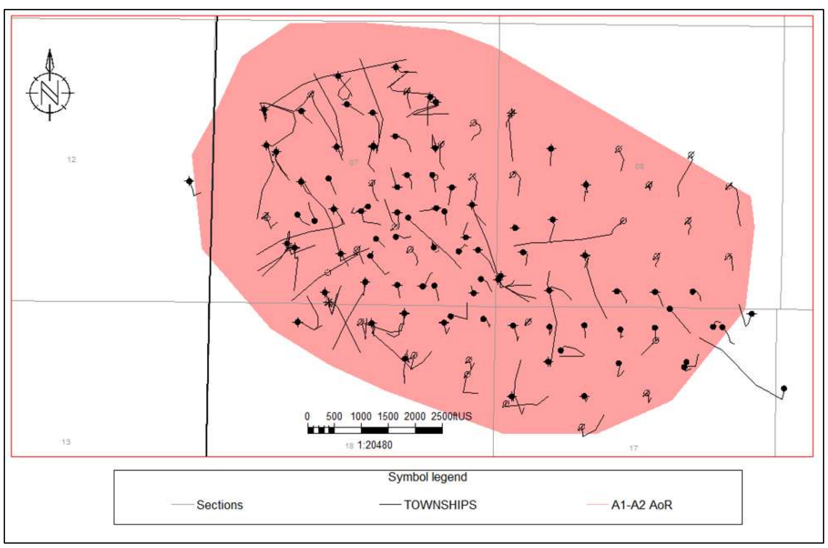
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 8 is a summary of the AoR wells (Figure 15) in Appendix 1 showing the drill date, status, and type.

**Table 8: Wells in the AoR and associated well status. All wells in the AoR penetrate the Reef Ridge Confining Zone.**

| Status | Well Count |
|---|---|
| Inactive | 70 |
| Active | 42 |
| Plugged and Abandoned | 40 |
| **Total** | **152** |

Wells in the AoR with a status of oil producing, and water injection are active development wells completed underneath the Monterey Formation A1-A2 reservoir and associated with a CalGEM Class II approval within the A3-A6 sand intervals.

**Figure 15: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation A1-A2 sequestration reservoir reviewed for corrective action.**




*Wells Penetrating the Confining Zone*

The depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Reef Ridge Shale confining zone. Table 8 is a summary of the AoR wells in Appendix 1 showing the drill date, status, type, and depth to Reef Ridge Shale confining zone.

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q1 2021.

The corrective action assessment included the generation of detailed wellbore/casing diagrams for each well (Appendix 1), determination of cement tops for each casing string, review of open perforations and cement plug depths. CTV can demonstrate that the USDW is protected and that with the abandonment of 14 wells, the Monterey Formation A1-A2 reservoir will be isolated.

Protection of USDW

For the Elk Hills A1-A2 project CTV assessed the protection of the USDW by all wellbores that penetrate the confining Reef Ridge Shale. A wells did not need corrective action that met the three criteria below:

1. Surface or intermediate casing over the USDW.
2. Cement over the USDW.
3. Cement in the annulus:
    a. Intermediate casing – cement above the above the surface casing shoe.
    b. Reef Ridge Shale – cement in annulus of production casing above the confining Reef Ridge Shale.

All wells within the AoR meet the criteria above, ensuring protection of the USDW.

Monterey Formation A1-A2 Isolation

Wells that will not be used for the Elk Hills A1-A2 Storage project that penetrate and are currently perforated in the Monterey Formation A1-A2 or the Etchegoin Formation will be abandoned prior to injecting $CO_2$. The abandonment of these wells is considered to be normal operating procedures to manage and minimize liabilities. There are 14 wells that meet this criterion as shown in Table 9.

**Table 9: Wells to be abandoned prior to injection as part of asset retirement obligations.**

| | |
|---|---|
| 342H-7R-RD1 | 353A-7R |
| 367X-7R | 335X-7R |
| 368A-7R | 336-7R |
| 374A-7R-RD1 | 348H-7R-RD1 |
| 367A-7R | 354X-7R |
| 355-8R | 361H-8R-RD3 |
| 365-7R | 313-17R |

### *Plan for Site Access*

CTV operates and owns 100% of the surface, mineral and pore space rights for the project where all activities will take place. As such, site access has been guaranteed for the duration of the project and for post-injection monitoring.

### *Corrective Action Schedule*

Corrective action for all wells withing the AoR will be completed before $CO_2$ is injected in the reservoir. This will ensure that $CO_2$ is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

## Reevaluation Schedule and Criteria

### *AoR Reevaluation Cycle*

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, $CO_2$ injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. $CO_2$ content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and $CO_2$ concentration data in 1 and 2 above.

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

### *Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation*

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Change in operations such as an increase in injection rates, or injection pressure.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

3. Seismic monitoring anomalies that are indicative of:

   a. The presence of faults near the confining zone that indicates propagation into the confining zone.

   b. Events reasonably associated with $CO_2$ injection that are greater than M3.5.

CTV will discuss any such events with the UIC Program Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.